A Study to Evaluate the Impacts of Increasing Wisconsin's Renewable Portfolio Standard

Methodology, Assumptions, Scenarios, and Results

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This study presents the methodology, assumptions, and results of an analysis of increasing Wisconsin's Renewable Portfolio Standard (RPS). The study was prepared under subcontract with the University of Wisconsin-Madison, as part of a larger study for the Wisconsin Division of Energy. The methodology, assumptions, and scenarios were developed in collaboration with these parties and underwent extensive review from the Wisconsin RPS Stakeholders Group. Adjustments were made to the analysis to incorporate feedback from the group, which includes representatives from utilities, environmental and public interest groups, and state agencies.

Methodology

This analysis uses a relatively simple and transparent spreadsheet model to project the costs, renewable generation mix, and carbon dioxide (CO_2) emission reductions of increasing Wisconsin's renewable portfolio standard (RPS). These impacts are calculated in the model by analyzing the interaction of renewable energy supply and policy-driven demand in a competitive wholesale market.

Model History and Evolution

This modeling approach was developed initially under contract to the Massachusetts Division of Energy Resources (DOER) in 2000 (and subsequently revised and updated in 2002) to project the costs and emission impacts of the Massachusetts RPS under various assumptions. The model developers derived the assumptions in consultation with DOER and its multi-stakeholder advisory group. When the model was initially developed in 2000, the wholesale competitive market structure and divesture of generation assets required of New England utilities resulted in a market with a distinct lack of long-term contracting for all resources, including renewables. As a result, the DOER model depicted that in each year the market would clear for *all* renewable generation and specific units chosen in one year may not be chosen in the next if other renewable generation became more economic.

The next generation of model development adapted the approach to model environments in which long-term contracting for renewable energy is expected to dominate:

- California (2001): For the Union of Concerned Scientists (UCS), the model was adapted into a tool to objectively evaluate the costs and benefits of various RPS design proposals.[1]
- New York (2001): For New York State Energy Research & Development Authority (NYSERDA), the model was used to assess the impact (cost, generation mix) of the Executive Order 111 renewable energy purchase mandate for state facilities.

With the current effort to model the Wisconsin RPS (2002-2003), the second generation spreadsheet model has been modified to reflect the specific parameters of the Wisconsin RPS, and to include additional features, including banking of renewable resource credits (RRCs).

Key Features of Modeling Approach

The modeling approach used in this analysis is designed to capture and reflect competitive wholesale RPS market characteristics. The approach has two key features:

Incremental Forward Contract Clearing Market. The model assumes that the renewable energy market is a market for long-term contracts that clears annually. Renewable energy and attributes are sold by generators under long-term contracts to credit-worthy customers in a market for long-term forward contracts that clears each year. The clearing price in each year is determined by the intersection of the incremental demand curve (i.e. the additional quantity needed in a particular year over and above the previous year's demand) with the aggregate incremental supply curve.

The supply curve is composed of the projected available quantity and cost of eligible renewable supply by resource and technology not previously committed. The available quantity is less than what is often thought of as the technical potential. Rather, it accounts for what could feasibly be built considering technical potential, siting/permitting constraints, land availability, project lead-times, etc, and it ignores the potential from renewable energy technologies that are well above the costs at which the market for renewables would clear. For example, we do not assume that any appreciable quantity of solar photovoltaics would be brought on-line solely to serve RPS demand. If solar PV were to be brought on-line as a result of other motivations (e.g. public benefits funds), it would effectively be a price-taker in the RPS market. The supply curve price is a long-term real levelized cost of each supply block.

The model assumes that the marginal unit sets the price for all eligible renewables contracted in a given year. The aggregate compliance costs are calculated as the weighted average of commitments made over time: the per-MWh costs under the current year as well as each previous year's long-term procurement (plus any transaction and administration costs).

Renewable Generation Premium. The renewable energy supply curve is built based on the required premium over the commodity market value for each renewable generator that is necessary to bring it on-line (i.e. to meet its levelized revenue requirement). This approach accounts for the fact that generators have different production profiles and hence commodity market values (i.e. revenues from the wholesale electricity market). So long as the quantity of renewables added in each year is small relative to the total supply, it is reasonable to assume that the generator may simply receive the commodity market value of its production at whatever time it produces, and for whatever contribution to reliability and ancillary services that it can provide. For example, if a plant needs \$50/MWh (levelized) over a long-term in order to attract financing and get built, and the commodity market value of all the conventional products and services that it can provide is \$35/MWh, its premium would be \$15/MWh.

The market clearing renewable generation premium is analogous to the market renewable resource credit (RRC) price. The Wisconsin RPS allows utilities to buy or sell RRCs to use for compliance with the standard. Under this system, the generator would receive the market value of its production plus the market-clearing RRC price, which is analogous to the structure of competitive wholesale electric commodity markets. So, the approach allows a comparison of renewable generation with different production profiles on an apples-to-apples basis, and broad interpretation of results for bundled energy and attributes, or attributes-only (RRCs).

Other key features of the model allow users to assess the impacts of:

- changes in natural gas prices and wholesale electric market prices[2]
- changes in eligible technologies and percentage targets
- different federal production tax credit assumptions
- renewable resource credit price caps and banking
- administrative and transaction costs.

Model Results

For a given set of inputs reflecting renewable energy demand and assumptions regarding the quantity and characteristics of available supply, the model will produce the following results:

- the incremental cost or savings of meeting the RPS requirement in each year
- the direct consumer costs of the RPS (in millions of dollars, ¢/kWh of retail sales, and dollars per month for a typical household)
- renewable energy development by fuel and technology (wind, biomass cofiring, dedicated biomass gasification plants, manure digestors, landfill gas, and hydro) for in-state development and imports
- renewable energy technology costs and supply
- carbon dioxide emission reductions.

Advantages of Modeling Approach

Although the model developers have extensive experience with traditional utility planning models, we have found that the behavior of RPS markets using tradable RRCs is not necessarily better captured by a dispatch model. In most respects, the uncertainties in assumptions swamp any variations driven by different modeling algorithms. By using certain inputs and results from widely accepted and reviewed utility dispatch models as inputs to the spreadsheet analysis, we can capture much of value of utility dispatch models.

In addition, we are not aware of any utility dispatch models that are designed to analyze the impacts of a state RPS. Thus, they are not capable of capturing the dynamics of an RPS market.

Most utility dispatch models also do not include a very detailed characterization of renewable energy resources and technologies.

The spreadsheet modeling approach was developed specifically to be transparent to multi-stakeholder groups. Perhaps its greatest advantage is the ability to do scenario analysis and sensitivities very rapidly (almost instantaneously) at very low cost. It is far superior for performing sensitivity analyses, in terms of ease and speed, compared to alternative approaches. This is important given the considerable uncertainty of many variables used in the analysis.

The model directly addresses unbundled revenue streams and RRC markets in a transparent, simple, and intuitive manner. It can easily depict renewable energy supply curves, supply stacks, and marginal resources. This capability has proven quite useful in making the results intuitive to users, and being easily able to explain *why* a particular result was arrived at (e.g. viewing the supply stack to see which units were marginal). This capability has proven effective in focusing discussion on model and market assumptions.

Finally, in our experience, the approach has withstood substantial stakeholder scrutiny. As discussed above, different versions of the model have received extensive review and input for analyses in Massachusetts, California, New York, and Wisconsin.

Limitations of Modeling Approach

Despite these advantages, there are certainly limitations to this approach. The primary limitation is that the modeling approach is static. It does not capture the second-order dynamic feedback effects of electricity and gas supply, demand and prices (i.e. substitution). For example, the addition of low- or zero-variable cost renewables to a supply mix typically will lower the marginal cost for electricity in a given area, by pushing the highest cost resources off the margin of the dispatch or bid stack. This lowers electricity prices for all consumers in the region by a small amount.

In addition, if natural gas generation is on the margin, not only will that generation be displaced, but less natural gas will be used in the region. The resulting shift in the demand for natural gas will place downward pressure on natural gas prices for generating electricity and for consumers that use natural gas and will help reduce natural gas price volatility. Several recent studies that have used models capable of capturing these effects have shown that an RPS can reduce consumer natural gas bills and help offset the costs of an RPS.[3] Thus, we believe that our approach is conservative and may overestimate the costs of an RPS in Wisconsin because it does not include these effects.

Analyses using utility planning models built on well-understood and accepted datasets can also accelerate buy-in on the non-renewable aspects of market simulation.

Assumptions

Our general approach was to use broadly accepted forecasts and other input data from credible sources as the basis for this analysis. While most of this data came from state and federal government agencies and the Electric Power Research Institute (EPRI), we also used data from non-profit energy research groups and existing renewable energy projects. In light of the recent volatility in electricity and natural gas markets, any projections of the future must be viewed with caution. Where appropriate, we adjusted input data and made conservative assumptions that would result in a higher estimate of RPS costs. We incorporated the following data into the model to assess the impacts of an RPS in Wisconsin:

- wholesale electricity prices
- capacity credit
- electricity demand
- renewable energy supply and costs
- renewable energy imports
- renewable resource credit banking
- financing costs
- transmission costs and constraints
- federal production tax credit
- administration and transaction costs

Each is discussed below.

Wholesale Electricity Prices
In this analysis, wholesale electricity price projections are based on data developed in 2001 by the Energy Information Administration (EIA) for the Mid-American Interconnected Network (MAIN) electricity reliability region, which includes Illinois and Eastern Wisconsin.[4] These prices are based on the marginal operating costs of power plants during nine different time periods in each year of the forecast. The different time periods represent on-peak, off-peak, and shoulder periods. Renewable generation for each technology is also broken down into these nine periods. The renewable generation in each time period is multiplied by the wholesale electricity price for the same time period to determine the amount of revenue renewable generators could obtain by selling their power into the wholesale market.

EIA's projections of wholesale electricity prices and the generation mix underlying this forecast are shown in Figure 1 and Figure 2. Most of the new generation in EIA's forecast is projected to come from increased coal generation at existing plants and new natural gas fired power plants. Using these projections, we calculated carbon dioxide emission rates for the marginal units, corresponding to the time periods discussed above. This allowed us to determine carbon emission reductions for new renewable energy facilities that are built to meet the RPS.

Figure 1. EIA Wholesale Electricity Price Forecast for MAIN

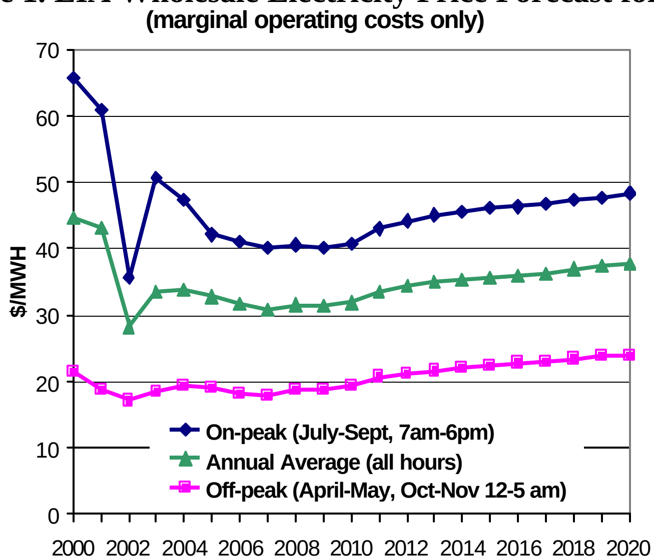
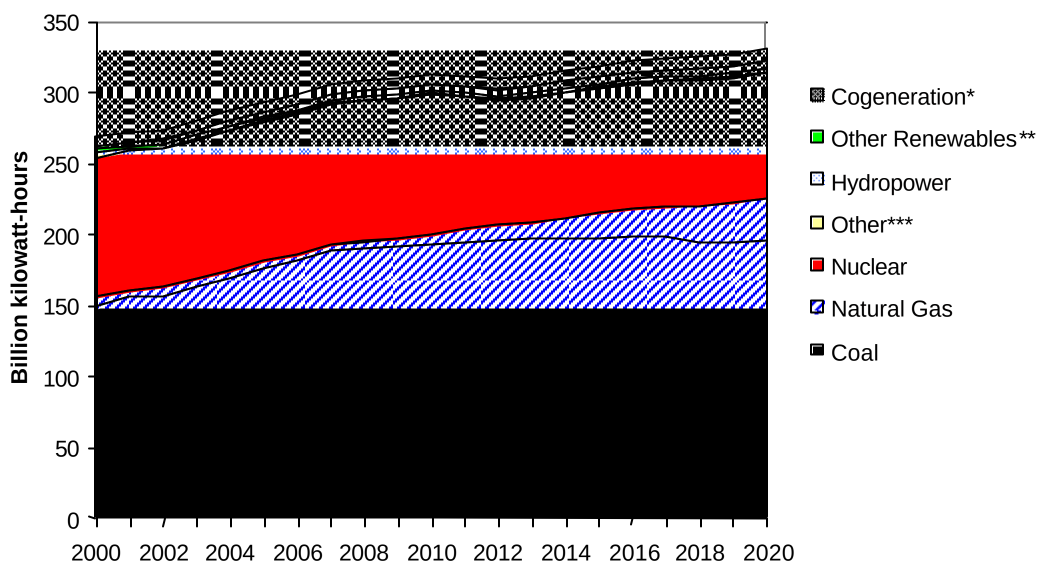


Figure 2. EIA Electricity Generation Forecast for MAIN (reference case)



*Includes all cogeneration except biomass.
**Includes wind, biomass, solar, and landfill gas.
***Includes oil, municipal solid waste, and other wastes.

Future wholesale electricity prices are highly sensitive to natural gas prices, as most new power plants are projected to use natural gas. Given the volatility in natural gas prices over the past few years, there is considerable uncertainty about future electricity prices. EIA's reference case natural gas price forecast from Annual Energy Outlook—2002 underlies the wholesale electricity price forecast. This forecast shows a smooth trajectory that does not correspond to the historically volatile prices. In addition, the Wisconsin RPS Stakeholders Group agreed that EIA's natural gas price forecast for the region that includes Wisconsin is too low. The group agreed to assume a natural gas price of $3.75/MMBtu in 2002, escalating at 1.5 percent per year in constant dollars. This is based on the midpoint of projections for a new natural gas cogeneration plant that Madison Gas and Electric is building in Madison and projections used in recent analyses by the Public Service Commission of Wisconsin. Using this natural gas price forecast increased EIA's annual average wholesale electricity price by approximately 25 percent by 2020.

Capacity Credit

Increasing renewable energy use will reduce the need for new conventional power plants that would have otherwise been built without the RPS. We assume that renewable energy technologies will get a capacity credit based on EIA projections of the annualized cost of a new natural gas combustion turbine plant. Dispatchable baseload renewable technologies—including dedicated biomass plants, landfill gas, and manure digestors—are assumed to get full credit. We assume new hydro projects at existing dams, which are partially dispatchable, will get a partial capacity credit equal to its average capacity factor of 50 percent.

Wind power, which is a variable output technology that only produces electricity when the wind is blowing, is assumed to get a partial capacity credit based on its effective load carrying capacity (ELCC). ELCC is a standard measure of capacity credit that is based on well-known reliability analysis techniques. Several studies that have applied this approach resulted in a capacity credit that is similar to the capacity factor of the wind project.[5] In a 2001 rate case before the Colorado Public Utility Commission, Xcel Energy and several other parties agreed to adopt the ELCC as the capacity credit measure, which resulted in a 30 percent capacity credit for a 162 MW wind farm under review.[6]

While the ELCC is under consideration in the regional power pools that include Wisconsin, they currently use a less sophisticated technique that typically results in a lower capacity credit for wind projects. Thus, to be conservative, we assume that a wind project would receive a capacity credit worth 75 percent of its capacity factor.[7] We also assume that imported wind generation will not get any capacity credit until 2009 when congestion is assumed to be relieved through investment in new transmission lines and upgrades of existing lines.

Electricity Demand

Electricity use is assumed to grow at 2 percent per year on average throughout the forecast, based on projections used by the Public Service Commission of Wisconsin (PSCW) and other regional forecasts. For example, PSCW Commissioner Robert Garvin indicated in a recent presentation that the PSCW base case projected an annual average growth rate of 2 percent until 2005.[8] EIA projected an annual average growth rate for MAIN of 1.9 percent between 2002 and 2010 and 1.5 percent between 2002 and 2020 in its reference case for Annual Energy Outlook—2002.

Renewable Energy Supply and Costs

The following renewable energy technologies are included in this analysis: wind, biomass co-firing in existing coal plants, dedicated biomass gasification plants, manure digestors on dairy farms, landfill gas, and hydro from recommissioning and uprating at existing dams. The quality and quantity of electricity production from these technologies varies greatly from location to location. For wind power, wind speed and technology performance, as reflected in the capacity factor (the average output divided by the maximum potential output), defines the quality of the resource and the amount of electricity production. For biomass technologies, the prime limitations are the cost, location, and availability of the biomass fuel. For manure digestors and landfill gas projects, the size of the operation is the primary factor. For hydro projects, the flow rate and vertical drop (head) define the quantity and quality of the resource. The supply and cost of each renewable resource and technology is discussed below.

Wind. Wisconsin's wind potential is based on a recent wind resource assessment by the Wisconsin Division of Energy, using a model called WindMap (see box below).[9] For this project, they calculated the amount of windy land area in Wisconsin by annual average wind speed (at a 60 meter hub height), within 20 miles of existing 69 kV or higher transmission lines, and excluding urban and environmentally sensitive areas such as state parks and wetlands. They also calculated the offshore wind energy potential in Lake Michigan and Lake Superior that is within 10 kilometers of land. This analysis shows that Wisconsin has an onshore potential of over 6,300 megawatts (MW) and an offshore potential of over 4,300 MW in areas with annual average wind speeds over 14.5 miles per hour and assuming a wind density of 5 MW per square kilometer.[10] For the purposes of this analysis, we conservatively assume that only 50 percent of this potential is available for development.

Costs for new wind projects are based on projections by the U.S. Department of Energy (DOE).[11] Using DOE assumptions, the 20-year levelized cost of onshore wind projects is projected to fall from 4-6 cents per kilowatt-hour today to 3-4.5 cents per kWh by 2010 and 2.5-4 cents per kWh by 2020, not including state or federal incentives or transmission costs (Figure 3). The cost reductions follow historic trends and are due to continued growth of industry and research and development (R&D) investments that lower capital costs and improve performance. DOE projects capacity factors to increase due to taller towers, longer blades, and efficiency improvements. They also assume a 50 percent probability of success with DOE's wind turbine R&D goals. Capacity factors for class 3 areas are extrapolated from the DOE projections for class 4 areas based on UCS estimates. Offshore wind costs are assumed to be over 50-66 percent higher than onshore costs based on projections from Global Energy Concepts for a recent RPS analysis in Massachusetts.

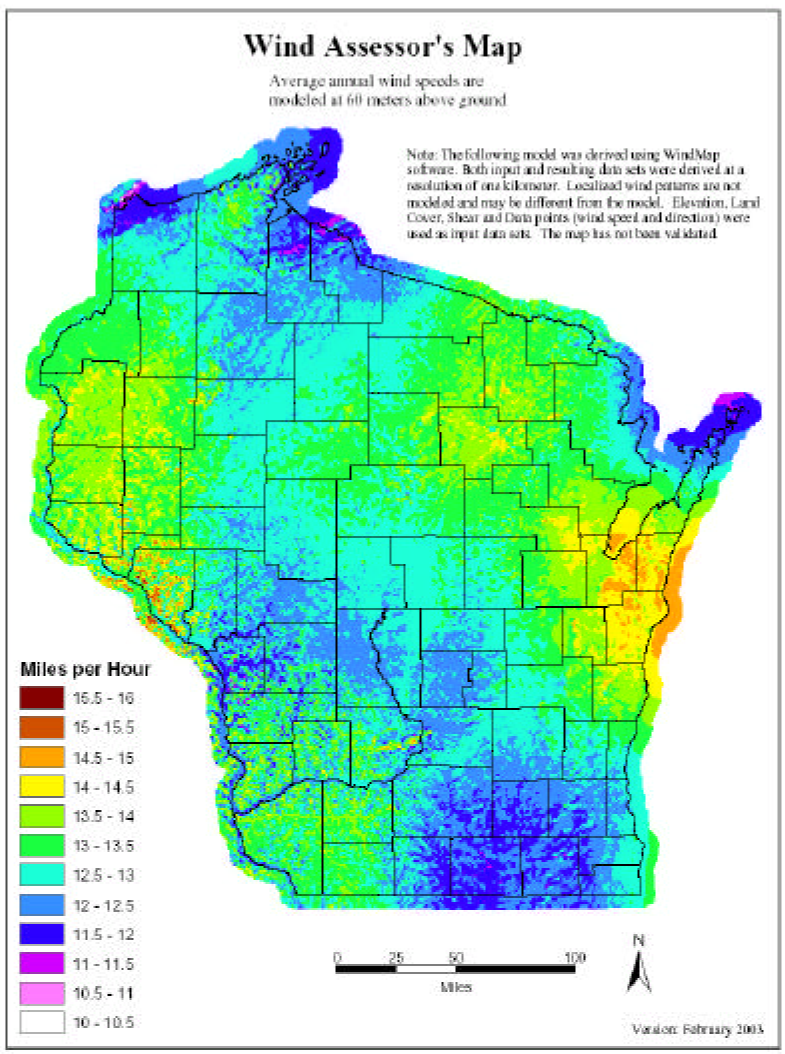
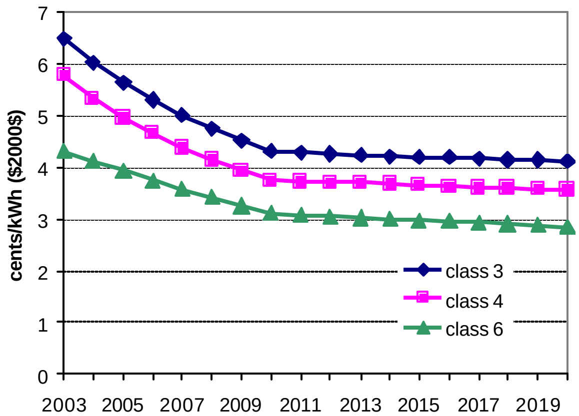


Figure 3. Wind Power Cost Projections
(20-yr Levelized Cost of Electricity in cents/kWh)*



*Not including incentives or transmission costs

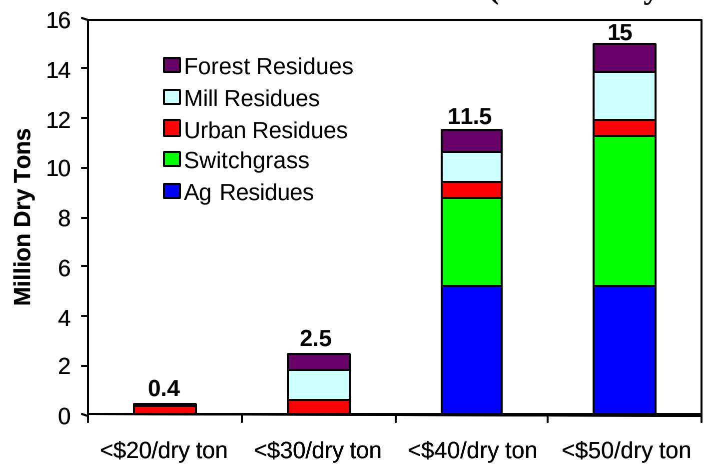
We also include costs for integrating wind into the electricity system to account for variations in wind power output that may increase the operating costs of the system. Utility planners typically refer to these costs as ancillary service costs. Several recent studies have shown that these costs are fairly small and vary according to the penetration of wind on the system.[12] For this analysis, we assume a cost of $1.90 per MWH for the 2.2 percent and 4.4 percent RPS scenarios and a cost of $2.50/MWH for the 10 percent RPS scenarios, based on a recent study completed for WE Energies.[13] Improvements in wind forecasting and distributing wind projects across a broad geographic area would result in lower costs.

Biomass. The potential available supply of biomass energy sources in Wisconsin is based on data from the Oak Ridge National Laboratory.[14] This data shows that Wisconsin could produce about 15 million dry tons of biomass at a cost of under $50 per dry ton, including transportation costs (Figure 4). This amount of biomass could produce the equivalent of about 33 percent of Wisconsin's electricity use in 2000 or about 3,900 megawatts (MW) of capacity. Agricultural residues and switchgrass, a native prairie grass that would be grown as an energy crop, make up the vast majority of this potential. However, these resources are available at a relatively higher cost than urban and mill residues.

The cost of converting biomass into electricity is based on two technologies-- biomass cofiring in existing coal plants and new dedicated biomass gasification plants. For this analysis, we include a biomass cofiring potential in Wisconsin of about 690 MW, assuming a 10 percent cofiring rate, and based on plant specific data from EPA's EGRID database. A few existing coal plants are excluded from the analysis due to a lack of data or because they are not operated enough to make a capital investment in cofiring economically viable. Biomass fuel supply and costs within a 50-75 mile radius of each coal plant are based on estimates from a geographic information system (GIS) analysis of the Oak Ridge National Lab data completed for a 2001 Midwest study.[15]

Plant specific coal prices for 1998 were also obtained from this study and are assumed to decline over time (in constant dollars) based on EIA projections. We assume capital costs of $200/kW for modifying pulverized coal boilers and $50/kW for modifying cyclone boilers based on data from DOE[16]. We also apply a heat rate penalty of one percent to account for the slightly lower efficiency that typically results from using biomass based on data from cofiring tests by Madison Gas and Electric (MGE) and Electric Power Research Institute (EPRI).[17] We also assume carbon dioxide emission reductions of 10 percent, which is equal to the cofiring heat rate, based on the MGE tests and EPRI study. This assumes that the biomass is grown, harvested, and used in a sustainable manner, so that there are no net carbon emissions. Costs for dedicated biomass gasification plants are based on projections by the EPRI and DOE.[18]

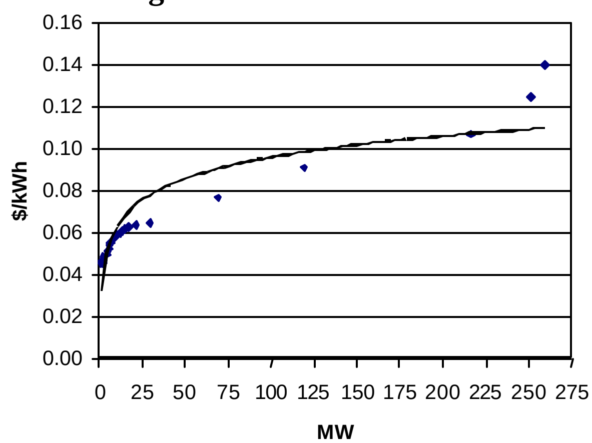
Figure 4. Wisconsin Biomass Potential (Million Dry Tons)*



*Includes transportation costs

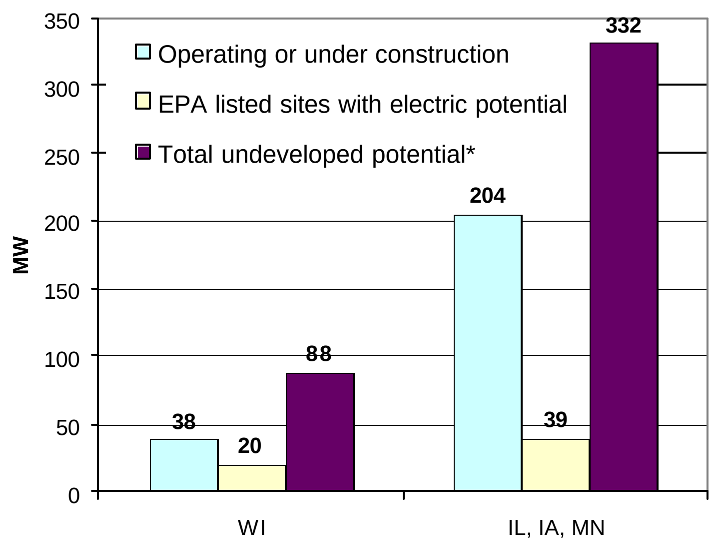
Manure Digestors. The potential for generating electricity from manure digestors on Wisconsin dairy farms is based on an analysis completed for this study by the Wisconsin Division of Energy (WDE). This analysis shows that Wisconsin has an overall technical potential of 250 MW from manure digestors and an economic potential of 70 MW for 7.7 cents/kWh and under on nearly 900 dairy farms with herds of 200 head and higher (Figure 5). The economic potential represents about 5 percent of all dairy farms in Wisconsin. WDE assumed that manure digestors would only be installed on larger farms due to economies of scale. WDE estimated the costs of producing electricity from manure digestors based on case study data from 6 dairy farms in the Midwest, and assuming an energy conversion factor of 6 cows per kilowatt of capacity.[19]

Figure 5. Manure Digestor Potential on Wisconsin Dairy Farms



Landfill Gas. We developed an estimate of the landfill gas potential in Wisconsin and neighboring states based on 2002 data from EPA's Landfill Methane Outreach Program.[20] This data shows that Wisconsin has about 38 MW of landfill gas capacity operating or under construction, and an electric only undeveloped potential of 20 MW, assuming one MW per million tons of waste in place (Figure 6). The total undeveloped potential in Wisconsin rises to 88 MW, when all landfills EPA lists as "direct use" are included. While direct use sites could potentially be used to generate electricity, we conservatively assume that only the sites EPA lists with electric only potential are available for development in this analysis. These sites are further broken down into high, medium, and low methane producing sites and different costs are assumed for these categories based on data from EIA.[21] Capital costs are projected to decline slightly over time due to technology learning.

Figure 6. Landfill Gas Potential (MW)



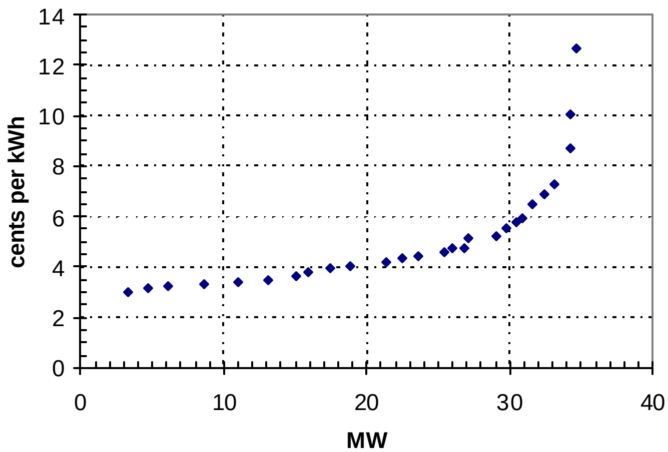
Hydro

The potential for additional hydro development in Wisconsin is based on data for uprating and recommissioning at existing dams from the Wisconsin Division of Energy.[22] Using site specific Idaho National Engineering Laboratory Hydro assessment for Wisconsin and WDE economic feasibility studies for 14 sites in the state, WDE estimates that there a potential to develop about 30 MW for under 6 cents per kilowatt-hour (Figure 7).

Renewable Energy Imports

Renewable energy facilities located in other states, that meet the eligibility criteria for the Wisconsin RPS, and that have a contract path to sell their power to Wisconsin utilities are eligible to meet the standard. In fact, Wisconsin utilities are currently purchasing generation from wind farms in Iowa to help meet the requirement. For this analysis, we assume that wind, biomass cofiring, and landfill gas projects could be developed in other states in the region to meet the Wisconsin RPS. We included these technologies because of their relatively low cost and large potential compared to other technologies. While there is some potential for manure digestors, new hydro, solar, and other renewable energy technologies in the region, the potential for these resources to be used for the Wisconsin RPS is fairly small. Developing supply curves for these resources was outside of the scope of this study.

Figure 7. Wisconsin's Hydroelectric Potential
Uprating and Recommissioning at Existing Impoundments



The region has an enormous wind energy potential that could be used to meet the Wisconsin RPS, particularly in the Plains states. For this analysis, we use wind energy potential data for the MAPP reliability region (IA, MN, ND, SD, NE and western WI) based on data used by EIA in the National Energy Modeling System. This data was originally developed for the U.S. wind resource assessment by DOE's Pacific Northwest Lab in the early 1990s.[23] The data includes the class 4 and higher windy land area in the region that is within 20 miles of existing transmission lines. The data also excludes all environmentally protected lands (such as parks and wilderness areas), all wetlands, all urban areas, 50 percent of forested lands, 30 percent of agricultural lands, and 10 percent of range and barren lands.

Even with these land-use exclusions, the MAPP region still has an enormous wind power potential that would be technically difficult to fully develop. Therefore, we conservatively assumed that only five percent of this potential would be available for development and export for the Wisconsin RPS.

We also included 1,140 MW of biomass cofiring imports and 60 MW of landfill gas that could potentially be developed in Illinois, Iowa, and Minnesota, based on the same data sources used to estimate Wisconsin's potential, as discussed previously. In addition, we added restrictions on wind, biomass, and landfill gas imports potentially available to Wisconsin to account for competing out-of-state demand due to renewable energy policies enacted in other states (e.g. Iowa and Minnesota), voluntary purchases from the green market, and transmission constraints (see below for more detail). For the purposes of this analysis, we conservatively assume that only 10 percent of the total import supply (after including the adjustments identified above) is available for the Wisconsin RPS in 2001, increasing linearly to 20 percent in 2010 and thereafter.

Renewable Resource Credit Banking

Wisconsin's RPS allows utilities to receive renewable resource credits for any excess renewable generation they purchase above their requirement in a given year. These credits can be traded to other utilities or banked for an unlimited period of time and used for compliance in future years. Enough eligible renewable generation is currently available in Wisconsin to meet the targets of all covered utilities through at least 2009 according to data submitted to the Wisconsin Division of Energy for the first two compliance periods (2001 and 2002) of the RPS. By banking the excess generation accumulated through 2009, we project that the utilities would have enough credits to meet their requirements through at least 2011. For this analysis, we assume that utilities will use the banked credits as soon as the demand for renewable generation exceeds 2002 levels. This is because the model projects the incremental cost of renewable resource credits to go down over time, as the cost of renewable technologies like wind decline and as natural gas prices increase. Thus, utilities can receive greater value for the banked generation, if they use the credits sooner.

Financing Costs

The cost of financing new power-plant construction is an important factor in determining the cost of the RPS. Since most renewable technologies are more capital intensive (but have lower operating costs) than competing fossil fuel technologies, higher financing costs tend to discourage renewable energy development and raise the cost of an RPS to consumers. For wind projects, we assume an annual carrying charge rate of 14.6 percent. This assumes a return on equity of 16 percent, a debt interest rate of 8.5 percent for a term of 12 years, a 60/40 debt/equity ratio, and a 5-year accelerated depreciation in accordance with federal law. For biomass gasification, biomass cofiring, and landfill gas, we assume an annual carrying charge of 16.8 percent based on the same assumptions as above, except we assume a 20-yr depreciation period instead of 5 years.[24] Financing costs for these technologies also include taxes, insurance, and the interest accrued during construction.

Financing costs for manure digestors assume a 15-year loan at a 6 percent interest rate based on data from existing projects developed in Wisconsin and neighboring states.[25] Financing costs for hydro projects assume a debt interest rate of 8 percent for 15 years, a 15 percent return on equity, and a 75/25 debt/equity ratio, based on feasibility studies developed for the Wisconsin Division of Energy.

Transmission Costs and Constraints

Transmission-system congestion has become a critical problem in many parts of the country including the Upper Midwest. The electrical transmission system in the United States was originally built to improve the reliability and efficiency of the electric power system. Its primary historical functions have been to provide avenues for the point-to-point transfer of blocks of energy between nearby regions allowing more efficient use of power generation facilities and to provide power in the event of failure of individual generating or transmission facilities. With increasing pressure from the Federal Energy Regulatory Commission (FERC) toward open access and regional operation, the transmission system is being called upon to serve a broader role. Over the past decade a number of new generation facilities have been interconnected with little if any expansion of transmission capability and investment in high voltage transmission has not kept pace with growth in electricity use.

Lack of sufficient transmission to meet market demand is a significant challenge for wind energy development today. However, it has been shown to be a solvable challenge in the Upper Midwest. A unique combination of utilities, communities, and environmentalists came together recently in support of several hundred miles of new high voltage transmission lines to move 825 MW of wind power to the Minneapolis/St Paul market from southwest Minnesota, resulting in a favorable approval of the needed facilities by the Minnesota Public Utilities Commission.[26]

Evolving bulk power markets will facilitate many of the conditions that support wind generation, including penalty-free imbalance markets and a liquid balancing market for wind generators to sell and buy power in near real-time. Results from a recent Midwest Independent System Operator (MISO) analysis of future transmission needs in the region that include developing 10,000 MW of wind power by 2007 confirm that many wind projects could be developed in the near-term.[27] The study indicates that many major transmission lines are only congested a small portion of the year leaving many hours when a wind farm could transmit on a curtailable basis, even though some specific areas in Wisconsin are congested more often than the rest of the region.

This analysis includes the cost of capital investments in new transmission lines and upgrades of existing lines and related equipment that will be needed to relieve congestion for renewable generation imported into the state. We assume that these investments would occur over the next six years so that congestion would be relieved by 2009.[28] We assume total investment costs of $200-$263/kW for imports, which are conservatively consistent with other recent projects and studies and current transmission planning practice in the region.[29] This includes $200/kW to build approximately 200 miles of new bulk (345 kV) transmission lines and upgrades to existing lines and related equipment for all renewable generators. For wind projects, we include an additional transmission interconnection cost of $10/kW for facilities that are within 5 miles of the existing transmission system, increasing to $63/kW for facilities within 10-20 miles, based on data from EIA.[30]

For new renewable energy facilities built in Wisconsin, we assume total costs of $150-$213/kW. This includes $150/kW in upgrades to existing lines and related equipment and some new lines for all renewable generators, and an additional $10-$63/kW in interconnection costs for wind projects. The costs for in-state renewable generators are lower than for imports because we assume there would be more investment in upgrades of existing lines and new lower voltage lines covering a shorter distance.

Some Wisconsin utilities on the Wisconsin RPS Stakeholders Group suggested that we use transmission cost estimates for the proposed Arrowhead-Weston line in Northwest Wisconsin for this analysis. The American Transmission Company in Wisconsin recently estimated that this line would cost $396 million to build 220 miles of new 345 kV lines and upgrade the existing system for an all-in cost of $1.8 million per mile. However, there is conflicting information on what the additional transfer capability will be from this investment, ranging from approximately 1000-2000 MW. This is equivalent to a total cost of $200-$400/kW. The costs used in this study are consistent with the lower end of this range. We also ran a test scenario using $400/kW for imports for the 10 percent by 2013 RPS with existing hydro capped at 0.6 percent of sales, which produced results that were nearly identical to the no imports scenario described below.

Although MISO plans to transition to day-ahead and real-time energy markets within two years, we also conservatively assume that renewable generation in other states will pay for point-to-point transmission service based on the current MISO transmission service tariff of $14.54/kW-yr for the American Transmission Company in Wisconsin. This translates into a charge of $4.74/MWH for wind (at a 35 percent capacity factor) and $2.07/MWH for baseload renewables (at an 80 percent capacity factor). We assume this would be for curtailable non-firm transmission service prior to 2009 and that this charge will remain in place throughout the forecast. We further assume that the capacity credit for imported renewable generation will be zero until congestion is relieved in 2009 through investment in new transmission and upgrades.

Finally, we conservatively assume that renewable energy generators will pay 100 percent of the capital costs for new transmission lines and upgrades and will not be paid back later through credits for transmission service.[31] In reality, any new transmission investments will have multiple uses and benefits and will become part of the broader electricity grid that is available for use by other generators and customers. Additional revenues would be generated from these other users that would offset some of the cost of the new lines. Thus, we believe this analysis overstates the cost of transmission investments that would be needed to meet the RPS.

Production Tax Credit
The federal government currently provides a production tax credit (PTC) to renewable energy facilities that use wind, biomass crops grown for specifically for electricity production, and poultry litter. The credit is worth 1.8 cents per kilowatt-hour for the first 10 years of operation for facilities placed in-service before January 1, 2004. Several bills have recently been introduced in Congress that would extend the PTC and expand eligibility to include other renewable energy technologies.

For this analysis, we assume that the PTC is extended through 2006 and expanded to include landfill gas, manure digestors, and biomass residues based on provisions included in the energy bills that have passed the House and Senate. New facilities installed through 2006 are assumed to get the full 1.8 c/kWh credit for 10 years. Co-firing of closed loop biomass (e.g. switchgrass and other energy crops) in existing coal plants is also eligible for the credit. However, cofiring projects would likely use a mix of biomass resources, including low cost biomass residues that would not be eligible for the credit. Thus, we assumed biomass cofiring projects would receive a reduced credit worth 0.6 c/kWh based on the share of closed looped biomass to total biomass available in Wisconsin for under $40/dry ton. While existing biomass and landfill gas facilities may also be eligible for a reduced credit, we do not include this credit in the analysis. Including this credit would lower the cost of meeting the RPS targets to Wisconsin.

Administration and Transaction Costs
We also included administrative and transaction costs based on estimates from the Public Service Commission of Wisconsin and by Sustainable Energy Advantage and La Capra Associates for a cost analysis of implementing the Massachusetts RPS.[32] The analysis includes cost estimates for:

- setting up a registry for renewable resource credits (RRCs)
- developing and purchasing computer systems for implementing the registry
- providing education and outreach to customers

- running the registry
- executing retail suppliers RRC transactions

These costs, while not trivial, are small enough that their impact on electricity prices would be negligible ($0.6/MWh in 2003 declining to $0.22/MWh in 2010) when spread over all electricity demand in the state.

Scenarios

We modeled four main RPS scenarios for this analysis that were specified by the Wisconsin Division of Energy, Public Service Commission, and University of Wisconsin. The first scenario illustrates the impacts of Wisconsin's existing RPS, in which all electric utilities in the state are required to produce at least 2.2 percent of their total retail electricity sales from eligible renewable resources by 2011. The law also allows a maximum of 0.6 percent of each utility's total retail sales to come from hydro facilities installed before 1998. In addition, the legislation excludes utilities that currently provide more than 10 percent of their summer peak demand from renewable energy sources from the RPS because they already have sufficient renewable generation to meet the requirement.

The second scenario assumes the standard is doubled to 4.4 percent by 2011 and we assume all other rules of the existing RPS are the same. The third scenario increases the standard to 10 percent by 2013, as recently proposed by Governor Doyle, and we assume all other rules of the existing RPS are the same, except that utilities that currently provide more than 10 percent of their summer peak demand from renewable energy are also required to meet the RPS.[33] The fourth scenario is the same as the third scenario, except we assume all of Wisconsin's existing hydro generation is eligible for the RPS. The renewable generation targets for these RPS scenarios are illustrated in Table 1.

We also completed four sensitivity scenarios on two key variables for the two 10 percent RPS runs. The first sensitivity assumes that no renewable energy imports are available to meet the RPS throughout the forecast. This scenario illustrates the impacts of meeting the entire requirement with in-state resources. The second sensitivity assumes no imports are available and the federal production tax credit (PTC) is extended through 2020 -- the last year of the forecast in the model. Table 2 describes the key assumptions for all of the scenarios.

Table 1. Renewable Generation Targets for Wisconsin RPS Analysis
(Eligible Renewable Generation Share of Total Retail Electricity Sales)

Year	2.2% by 2011	4.4% by 2011	10% by 2013
2001	0.50%	0.50%	0.50%
2002	0.50%	0.50%	0.50%
2003	0.85%	0.85%	0.85%
2004	0.85%	0.85%	1.00%
2005	1.20%	1.36%	2.00%
2006	1.20%	1.86%	3.00%
2007	1.55%	2.37%	4.00%
2008	1.55%	2.88%	5.00%
2009	1.90%	3.39%	6.00%
2010	1.90%	3.89%	7.00%
2011	2.20%	4.40%	8.00%
2012	2.20%	4.40%	9.00%
2013 (and after)	2.20%	4.40%	10.00%

Table 2. Key Assumptions for the Wisconsin RPS Scenarios

Scenario/RPS Targets	Existing Hydro Eligible for RPS	Covered Utilities	Production Tax Credit Extension	Renewable Energy Imports Included?
2.2% by 2011	0.6% of total sales	All utilities with existing renewables < 10% of sales	Through 2006	Yes
4.4% by 2011	0.6% of total sales	All utilities with existing renewables < 10% of sales	Through 2006	Yes
10% by 2013	0.6% of total sales	All utilities	Through 2006	Yes
10% by 2013	All Wisconsin hydro	All utilities	Through 2006	Yes
Sensitivity runs				
10% by 2013	0.6% of total sales	All utilities	Through 2006	No
10% by 2013	0.6% of total sales	All utilities	Through 2020	No
10% by 2013	All Wisconsin hydro	All utilities	Through 2006	No
10% by 2013	All Wisconsin hydro	All utilities	Through 2020	No

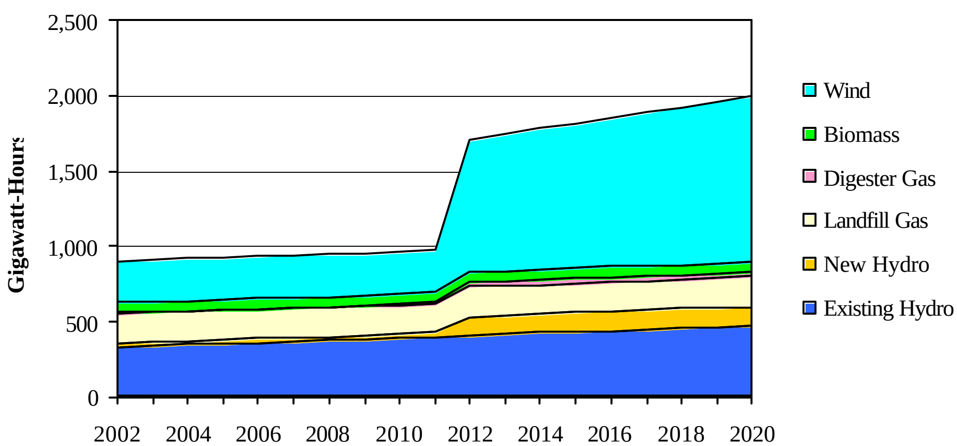
Results

The results of the analysis fall into three categories. First, we project the mix of renewable generation that will be developed to meet the various RPS requirements. Second, we estimate the reduction in carbon emissions that would result from renewable electricity displacing natural gas and coal generation. Last, we quantify the impact of RPS targets on consumer electricity bills in Wisconsin.

Renewable Energy Supply

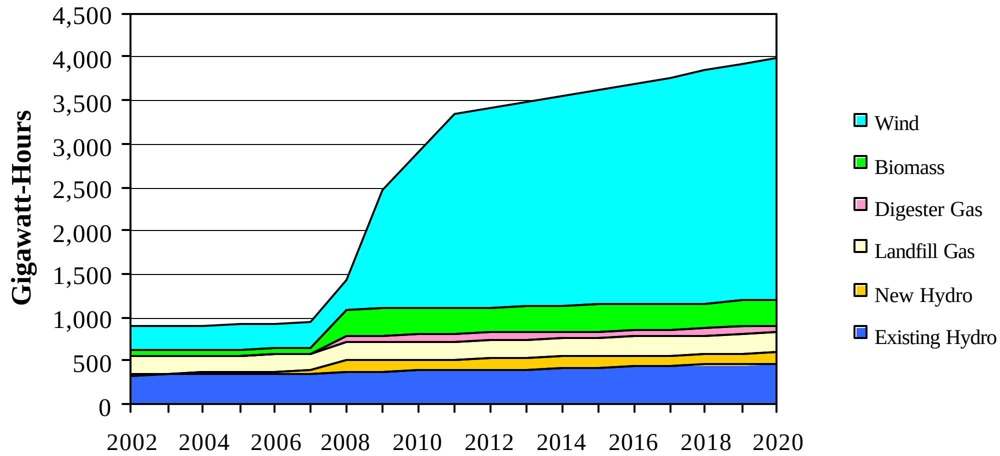
2.2 percent by 2011 RPS. Under Wisconsin's existing RPS, utilities have already installed or purchased enough eligible renewable generation statewide to significantly exceed the RPS targets of 0.5 percent in 2001 and 2002 – the first two compliance periods. At the end of 2002, eligible renewable generation was equal to 1.5 percent of total covered electricity sales. With unlimited banking of excess renewable generation, enough renewable generation is currently available statewide to meet the RPS targets of all covered utilities through 2011. The model projects that new renewable generation is not needed until 2012, after the banked generation runs out (Figure 8). Most of the new generation that is needed for the RPS is projected to come from imported wind power and a small amount of new in-state digestor and hydro generation. Imported wind power is projected to be cheaper than building new wind, biomass, and landfill gas projects in Wisconsin after transmission constraints are assumed to be relieved in 2009.

Figure 8. Renewable Generation, 2.2 percent by 2011 RPS



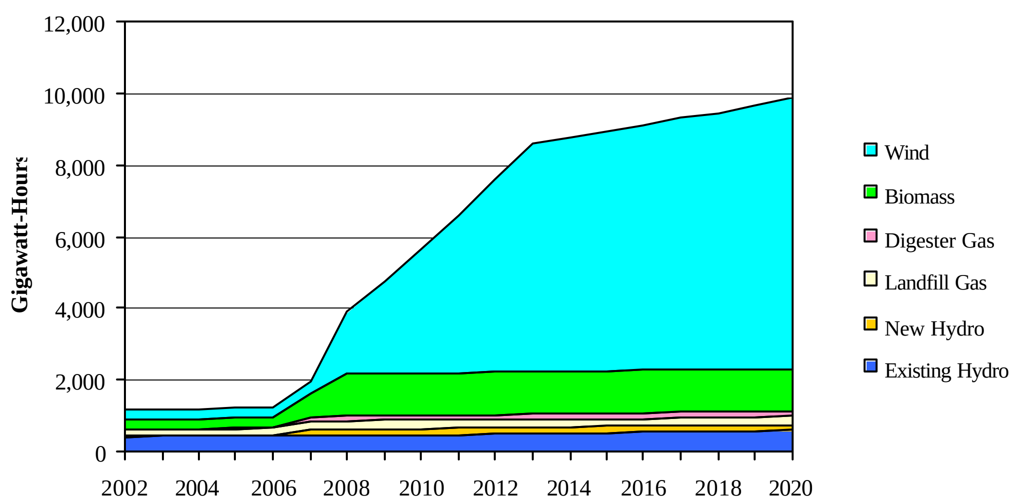
4.4 percent by 2011 RPS. Under this scenario, new renewable generation would be needed by 2008 to meet the higher targets (Figure 9). In 2008, the model projects nearly 80 megawatts (MW) of new wind, biomass co-firing, digestor gas, landfill gas, and hydro capacity would be built in Wisconsin to meet the RPS. Starting in 2009 and continuing throughout the forecast, all of the new renewable generation developed for the RPS is projected to come from imported wind power. By 2013, the model projects over 500 MW of imported wind will be added to meet the RPS. As discussed above, we assume new transmission lines and upgrades will be built to relieve congestion by 2009 and new rules for the regional transmission system will be in place to reduce the barriers and costs of delivering imported wind power.

Figure 9. Renewable Generation, 4.4 percent by 2011 RPS



10 percent by 2013 RPS. Increasing the RPS targets to 10 percent by 2013 would facilitate the need to add new generation by 2007 – one year earlier than the 4.4 percent RPS (Figure 10). In 2008, the model projects that nearly 400 MW of new renewable capacity would be added in Wisconsin, including 230 MW of new wind projects, 110 MW of biomass co-firing at existing coal plants, as well as nearly 60 MW of new hydro, digestor, and landfill gas generation. The model also projects that 185 MW of imported wind capacity and a small amount of imported biomass cofiring would be added by 2008. Even with transmission constraints on imports still assumed to be in place in 2008, the model projects that it is cheaper to import a modest amount of renewable generation during off-peak hours than develop additional renewable facilities in Wisconsin. By 2013, imported wind capacity is projected to increase to over 1,350 MW.

Figure 10. Renewable Generation, 10 percent by 2013 RPS



10 percent by 2013 RPS with All Hydro. Increasing the RPS to 10 percent and allowing all of Wisconsin's existing hydro to be eligible would delay the need to add new renewable generation until 2010 (by 3 years) compared to the previous scenario (Figure 11). While the model projects nearly 50 MW of new wind, hydro, and digestor capacity will be developed in Wisconsin to meet the RPS, the vast majority of new development is imported wind power, as with the other scenarios. By 2013, the model projects over 1,400 MW of imported wind capacity will be developed. Allowing all of Wisconsin's existing hydro to be eligible for the RPS would reduce the need for new renewable generation by 26 percent by 2013 compared to the 10 percent RPS with existing hydro capped at 0.6 percent of retail sales. The additional existing hydro generation would largely displace new biomass cofiring, wind, landfill gas, digestor gas, and hydro projects that would have otherwise been developed in Wisconsin.

Figure 11. Renewable Generation, 10 percent by 2013 RPS with All Hydro

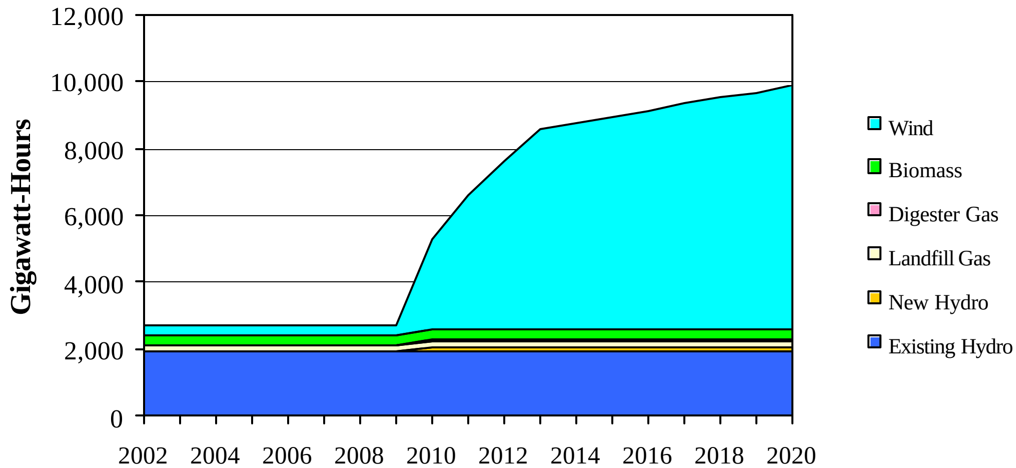


Table 3. Renewable Energy Generation (million kWh)*

	2002	2013			
Source		**2.2% by 2011**	**4.4% by 2011**	**10% by 2013**	**10% by 2013 All hydro**
Biomass**	68	68	295	1,179	284
Wind	281	907	2,345	6,354	6,016
Digester Gas	2	31	84	155	31
Landfill Gas	196	196	213	224	225
New Hydro	24	127	127	169	127
Existing Hydro	328	407	407	516	1,914
Total	899	1,736	3,472	8,597	8,597

*The 2.2 percent and 4.4 percent RPS scenarios only include utilities with current renewable generation of less than 10 percent of total sales, while the 10 percent RPS scenarios include all Wisconsin utilities.
**Existing biomass generation of 216 gigawatt-hours from utilities with current renewable generation of 10 percent or more current electricity sales is not included in 2002 or the 2.2 percent and 4.4 percent RPS scenarios, but it is included in the 10 percent RPS scenarios.

Table 4. Renewable Energy Capacity (Megawatts)*

	2002	2013			
Source		**2.2% by 2011**	**4.4% by 2011**	**10% by 2013**	**10% by 2013 All hydro**
Biomass**	24	24	61	230	84
Wind	118	274	644	1,711	1,568
Digester Gas	2	6	14	24	6
Landfill Gas	31	31	33	35	35
New Hydro	7	31	31	40	31
Existing Hydro	86	107	107	135	502
Total	268	472	889	2,175	2,226

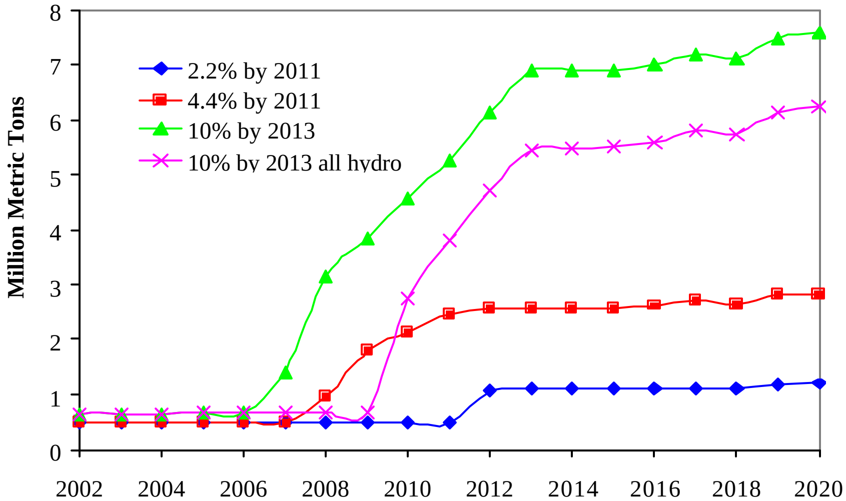
*The 2.2 percent and 4.4 percent RPS scenarios only include utilities with current renewable generation of less than 10 percent of total sales, while the 10 percent RPS scenarios include all Wisconsin utilities.
**Existing biomass capacity of 60 MW from utilities with total renewable generation of 10 percent or more current electricity sales is not included in 2002 or the 2.2 percent and 4.4 percent RPS scenarios, but it is included in the 10 percent RPS scenarios.

Figures 8-11 and Tables 3-4 only include the projected renewable generation that is needed to meet the RPS targets. Some Wisconsin utilities have announced plans to build or purchase generation from up to 300 MW of new wind capacity and 50 MW of new biomass capacity that is not explicitly included in this analysis.[34] Most of this new capacity is projected to be installed in the next 2-5 years. We estimate that this new capacity would produce enough electricity to provide approximately 1.6 percent of Wisconsin's total electricity sales in 2006. While this generation is not needed to meet the RPS targets in the early years (before 2006) of any of the scenarios, it could be banked and applied to future requirements. If this occurs, it would tend to smooth out the curves show in Figures 8-11.

Carbon Dioxide Emission Reductions

New renewable generation developed under the RPS would reduce carbon dioxide (CO_2) emissions – the main heat-trapping gas responsible for global warming – from new and existing coal and natural gas power plants that would have generated electricity without the RPS. In 1990, power plants were responsible for over one-third of total greenhouse gas emissions in Wisconsin.[35] Between 1990 and 1999, power plant CO_2 emissions in Wisconsin increased by 22 percent.[36] By 2013, power plant CO_2 emissions would be reduced by over 1 million metric tons under the 2.2 percent RPS to nearly 7 million metric tons under the 10 percent RPS with existing hydro capped at 0.6 percent of total sales (Figure 12). This is equivalent to a 2.7 percent to 17.3 percent reduction from 1999 levels.

Figure 12. Carbon Dioxide Emission Reductions



Impact on Consumer Electricity Bills in Wisconsin

Under all of the RPS scenarios, we project consumer electricity bills in Wisconsin to be between \$4.7 million to \$5.8 million (in constant 2001\$) higher from 2003 to 2006 than without the RPS (Figure 13). This is equivalent to paying 5-6 cents more per month on the electric bill of a typical Wisconsin household using 700 kilowatt-hours (kWh) per month on average (Figure 14) or a slight increase in electricity prices to all consumers of about 0.007 cents per kWh (Figure 15).

2.2 percent by 2011 RPS. By 2011, the RPS would increase consumer electricity bills by a maximum of \$6.1 million, or nearly 5 cents more per month for a typical household. After 2011, the cost to consumers would gradually fall to close to zero by 2020, because the small amount of imported wind generation added during this time is projected to be cheaper than building new coal and natural gas power plants.

4.4 percent by 2011 RPS.

By 2008, the RPS would increase consumer electricity bills by \$8.4 million, or about 8 cents more per month for a typical household. After this time, the cost to consumers gradually increases to a maximum of \$9.1 million in 2012 and then gradually falls to \$7.3 million in 2020 (6 cents/month for a typical household), as relatively low cost imported wind is developed to meet the higher RPS targets.

10 percent by 2013 RPS. After 2006, costs to consumers would steadily increase to a maximum of \$37 million higher in 2014 than without the RPS. This is equivalent to 30 cents more per month for a typical household or a slight increase in electricity prices of 0.042 cents/kWh for all consumers. After 2014, the cost to consumers falls slightly as relatively small amounts of low cost imported wind is developed to meet the 10 percent targets.

10 percent by 2013 RPS with All Hydro. After 2006, consumer electricity costs increase slightly under the RPS, reaching a maximum of \$9.9 million higher in 2014. This is equivalent to 8 cents more per month for a typical household or a slight increase in electricity prices of 0.011

cents/kWh for all consumers. After this time, the cost to consumers stays relatively fixed through 2020. As discussed above, delaying the need to add new generation by 3 years compared to the 10 percent RPS scenario with existing hydro capped at 0.6 percent of retail sales would eliminate the need to add higher cost biomass and in-state wind generation until imported wind becomes available at a lower cost after transmission congestion is assumed to be relieved in 2009.

Figure 13. Change in Consumer Electricity Bills

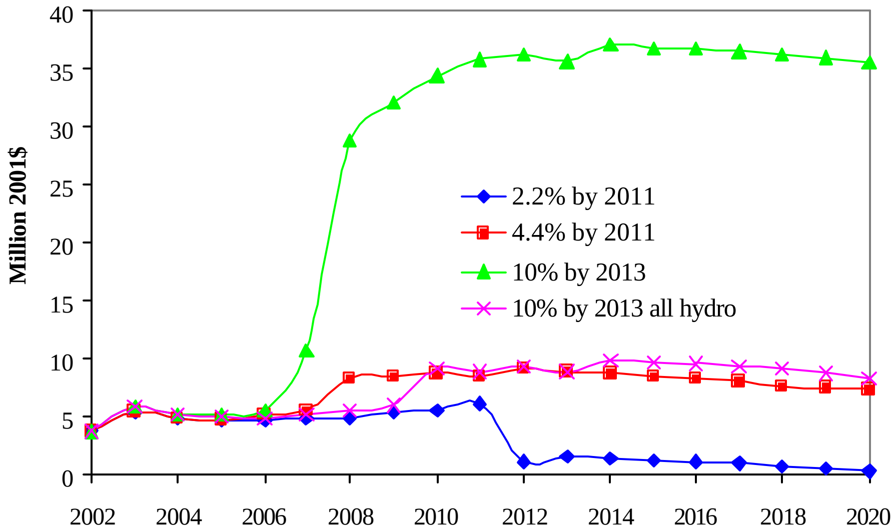


Figure 14. Change in Typical Household Electricity Bill

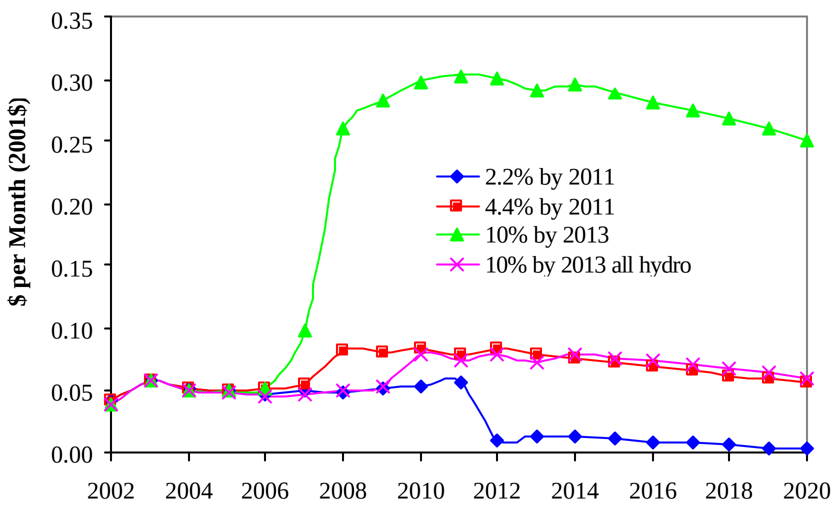
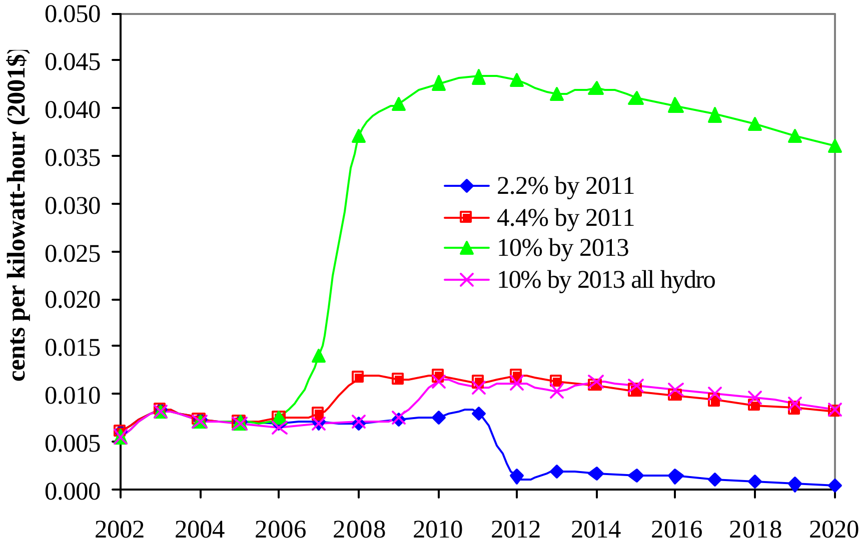


Figure 15. Change in Electricity Prices



Sensitivity Analysis

We also completed a sensitivity analysis on two key variables for the two 10 percent RPS runs. The first sensitivity assumes that no renewable energy imports are available to meet the RPS throughout the forecast. This scenario illustrates the impacts of meeting the entire requirement with in-state resources. The second sensitivity assumes no imports are available and the federal production tax credit (PTC) is extended through 2020 -- the last year of the forecast in the model. In addition, each of these sensitivity scenarios were run with existing hydro capped at 0.6 percent of retail sales and with all Wisconsin hydro eligible for the RPS.

The assumption for the scenarios above that the PTC will be extended through 2006 has little impact on the results, as the model projects that no new renewable generation is needed until 2007 at the earliest to meet the 10 percent RPS targets. There are several bills in Congress to extend the PTC beyond 2006, including a permanent extension. Thus, the PTC extension through 2020 sensitivity scenario analyzes the impacts of implementing a permanent extension.

10 percent by 2010 RPS. Under the no imports/PTC extended through 2006 scenario, the model projects that the vast majority of new development under a 10 percent RPS will come from in-state wind power and some additional biomass cofiring at existing coal plants. By 2013, the model projects over 1,700 MW of new wind capacity and 250 MW of biomass cofiring capacity would be built in Wisconsin (Figure 16). However, this in-state wind and biomass development comes at a higher cost than the scenario when imports are eligible for the RPS. The cost of the RPS would increase from about $6 million in 2003 to nearly $63 million in 2013, compared to $37 million in 2013 when imports are eligible (Figure 17). This is equivalent to 6 cents more per month for a typical household in 2003 rising to 51 cents per month in 2013 (Figure 18).

Under the no imports/PTC extended through 2020 scenario, the model projects even more in-state wind development, which in turn displaces the biomass cofiring capacity projected under the no imports/PTC through 2006 scenario. This is because wind is assumed to get the full value of the PTC (1.8 cent/kWh for 10 years), while biomass cofiring is assumed to receive partial credit (0.6 cents/kWh) based on current proposals before Congress. Extending the PTC through 2020 also has a major impact on reducing the cost of the RPS. The cost to Wisconsin electricity customers would reach a maximum of $6.8 million in 2008 and decline to zero by 2011. By 2013, the model projects that customers would save nearly $20 million per year, or 16 cents per month for a typical household, increasing to $29 million or 21 cents per month in 2020. The model projects that extending the PTC through 2020 would make wind power development in Wisconsin more competitive than new natural gas and coal plants starting in 2009.

Figure 16. Renewable Generation, 10 percent by 2013 RPS (No imports/PTC through 2006)

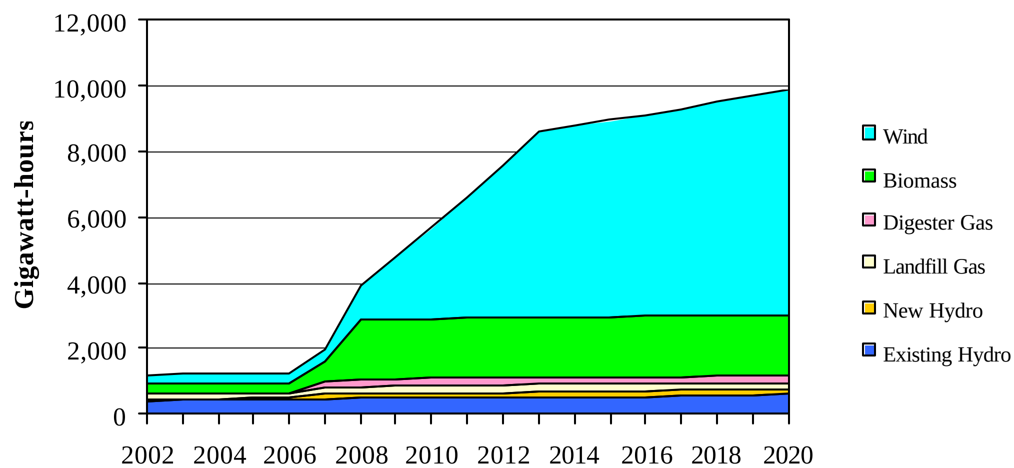


Figure 17. Change in Consumer Electricity Bills, 10 percent by 2013 RPS

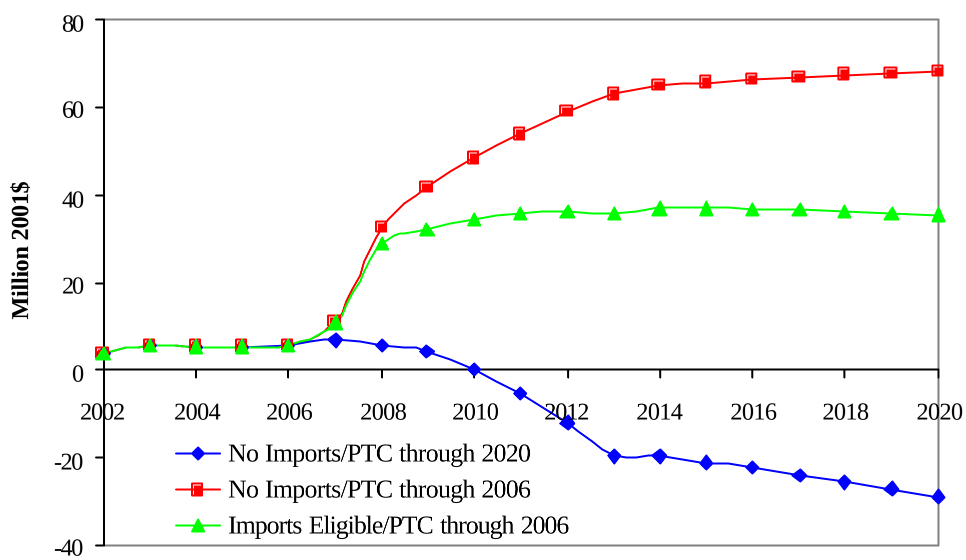
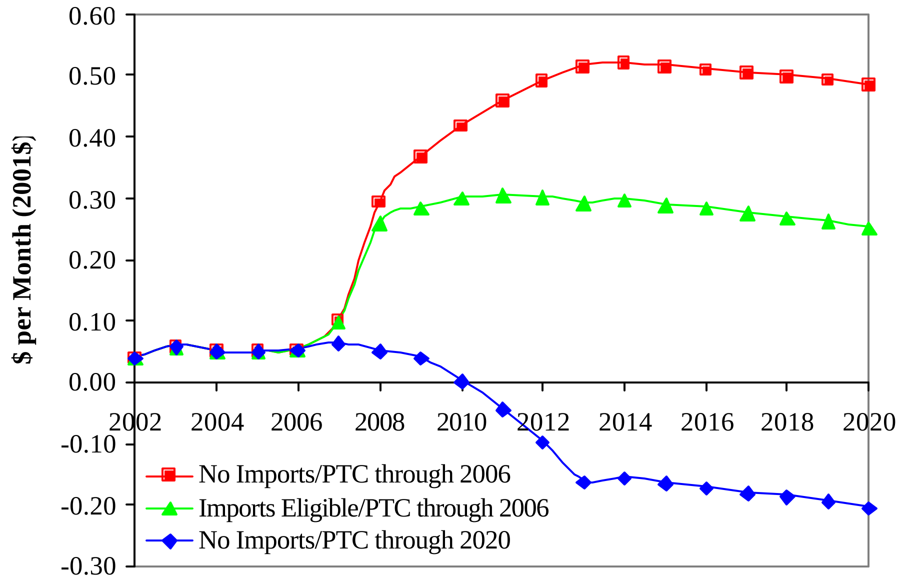


Figure 18. Change in Typical Household Electricity Bill, 10 percent by 2013 RPS



10 percent by 2010 RPS with All Hydro. Under the no imports/PTC through 2006 scenario, less new wind development and new biomass cofiring would be needed in Wisconsin when all of Wisconsin's existing hydropower is eligible for the RPS than when hydro is capped at 0.6 percent of retail sales (Figure 19). However, wind development in Wisconsin would still reach 1,670 MW by 2013. Including all of Wisconsin's existing hydro would also delay the need to add new renewable generation until 2010 (by 3 years), which would lower the cost of the RPS. The cost stays fairly level at around $5-6 million per year between 2003 and 2009, and then increases to over $40 million by 2013 or 33 cents per month for a typical household (Figure 20 and Figure 21).

Under the no imports/PTC extended through 2020 scenario, the renewable generation mix is about the same as the no imports/PTC through 2006 scenario, but the cost to electricity customers is significantly lower. Through 2009, the RPS would cost roughly $5-6 million per year or 5 cents per month for a typical household. By 2010, the model projects that consumers would save nearly $4 million and these savings would increase to over $30 million in 2013 (25 cents per month for a typical household) and over $40 million by 2020.

Figure 19. Renewable Generation, 10 percent by 2013 RPS with All Hydro (No imports/PTC through 2006)

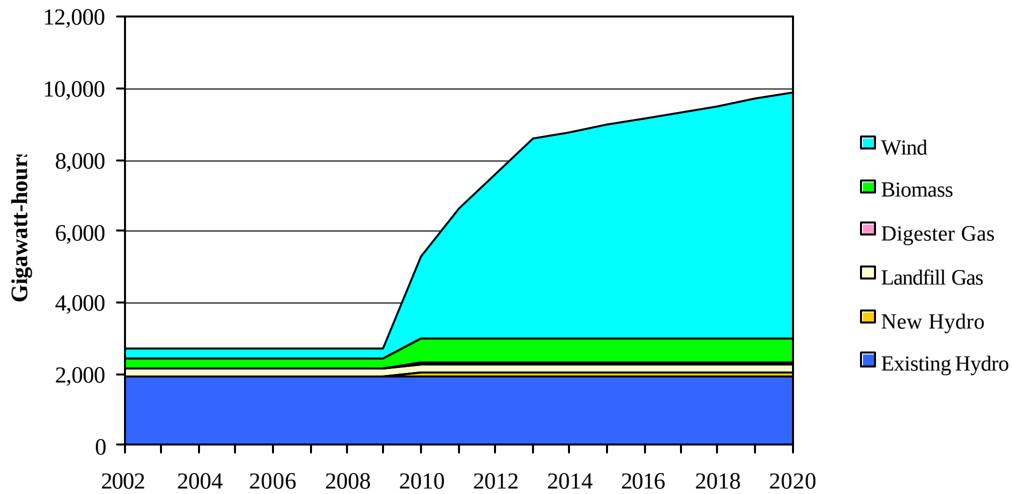


Figure 20. Change in Consumer Electricity Bills, 10 percent by 2013 RPS with All Hydro

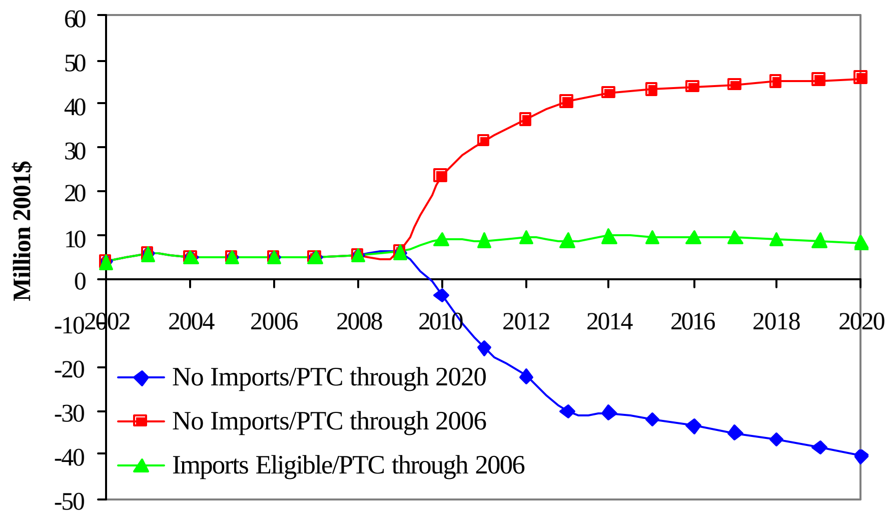
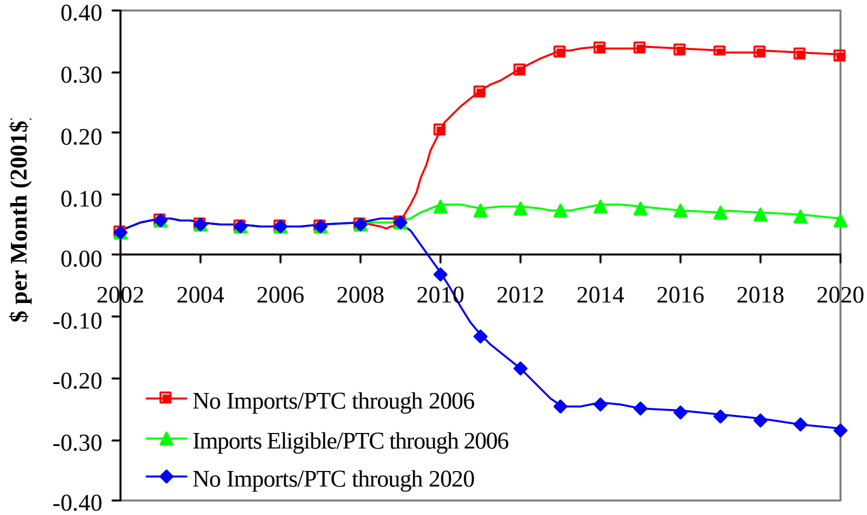


Figure 21. Change in Typical Household Electricity Bill, 10 percent by 2013 RPS with All Hydro



Endnotes

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[2] An input price of natural gas influences the wholesale market price forecast. The relationship of gas to electric prices is based on the reference and high natural gas price cases of the Energy Information Administration's Annual Energy Outlook—2002 for the MAIN reliability region that includes Wisconsin.
[3] For example, several national RPS studies by EIA and UCS have shown this effect. See Union of Concerned Scientists, *Renewing Where We Live*, 2002, and UCS fact sheet "EIA Study: National Renewable Energy Standard of 20 percent is Easily Affordable," online at www.ucsusa.org. In January 2003, the Tellus Institute also completed a modeling effort using EIA's NEMS model to assess the effects of a proposed RPS in Rhode Island. They concluded that although there was a positive cost to Rhode Island electric ratepayers, there were net savings to consumers from a regional and societal perspective, in large part due to the effects described here.
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[6] R. Lehr, J. Nielson, S. Andrews, and M. Milligan, *Colorado PUC's Xcel Wind Decision*, Windpower 2001.
[7] This assumption was used by EIA in the version of the National Energy Modeling System used to produce Annual Energy Outlook—2002. For example, a project with a 30 percent capacity factor would receive a capacity credit of 22.5 percent (0.3 * 0.75).
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[9] The wind map is available from the Wisconsin Division of Energy at http://www.doa.state.wi.us/docs_view2.asp?docid=55
[10] Wind density is based on data from the National Renewable Energy Laboratory.
[11] DOE Office of Power Technologies, Government Performance Review Act (GPRA), 2003 and FY03 U.S. DOE Wind Program Internal Planning Documents, Summer 2001. The GPRA study was peer reviewed by AD Little and industry experts. Class 3 wind projects assume DOE cost projections for class 4 and capacity factors from current wind projects in Wisconsin increasing at the same rate as DOE's class 4 capacity factor projections.
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[25] Wisconsin Division of Energy and Kramer (2002). The 6 percent loan is a proxy, which assumes that some equity and/or reduced interest on loans will come from federal or state grant or loan programs.

[26] Minnesota Public Utilities Docket No. E-002/CN-01-1958

[27] *Midwest ISO Transmission Expansion Plan 2003*, June 2003, http://www.midwestiso.org

[28] We include these costs for all projects built before and after 2009, even though we assume congestion is not relieved until 2009.

[29]This is equivalent to a total cost of $1 million to $1.32 million per mile of new line to move an estimated 1000 MW of power. The U.S. Department of Energy's *National Transmission Grid Study Issue Papers* (May 2002) assumes a total cost for building new 345 kV lines of $900,000/mile (including a 20 percent adder for new substations and related equipment) to deliver 900 MW of power, which is equivalent to $200/kW for a 200 mile line. Xcel Energy recently received approval from the Minnesota Public Utilities Commission to build new 345 kV lines and upgrade existing lines and related infrastructure to accommodate 825 MW of wind power in Southwest Minnesota at a cost of $160 million or $194/kW. MISO & MAPP are using $364,000 (1998$) per mile for new 345kV lines plus $900,000 for each complete line terminal (breaker bays, disconnects, relays, etc) for planning. Xcel has recently been using $450,000 per mile (2001$) when planning for new 345kV lines. A recent study, *Delivering 2000 MW of Wind Energy to the Metropolitan Centers in the Midwest* (http://www.state.ia.us/dnr/energy/programs/wind/Metro percent20Wind percent20Non-Technical percent20Version.pdf), estimated a total transmission cost of $110/kW to deliver 2000 MW of new wind power in Southwest Wisconsin to load centers in Southeast Wisconsin.

[30] EIA, Model Documentation Renewable Fuels Module of the National Energy Modeling System, DOE/EIA-M069(2002), February 2002.

[31] As a default pricing policy applicable to transmission providers that are not independent, FERC Order 2003 requires that network upgrades for new interconnection facilities be funded initially by the interconnection customer unless the transmission provider elects to fund them. The interconnection customer would then be entitled to a cash equivalent refund (i.e., credit) equal to the total amount paid for the network upgrades, including any tax gross-up or other tax-related payments. The refund would be paid to the interconnection customer on a dollar-for-dollar basis, as credits against the interconnection customer's payments for transmission services, with interest, within five years of the date the network upgrades are placed in service, as payments are made under the tariff for transmission services. FERC's reasoning for crediting ensures that the interconnection customer will not ultimately have to pay both incremental costs and an average embedded cost rate for the use of the transmission system. Also, the Commission's crediting policy helps to ensure that the interconnection customer's interconnection is treated comparably to the interconnections that a non- independent transmission provider completes for its own generating facilities. The transmission provider has traditionally rolled into its transmission rates the cost of network upgrades required for its own interconnections, and the Commission's crediting policy ensures that network upgrades constructed for others are treated the same way.

[32] Personal Communication with Paul Helgeson, PSCW Staff, 2002 and Robert Grace, Douglas Smith, Karlynn Cory, and Ryan Wiser, *Massachusetts Renewable Portfolio Standard Cost Analysis Report*, prepared for the Massachusetts Division of Energy Resources, December 2000.

[33] Governor Jim Doyle remarks, Metropolitan Milwaukee Association of Commerce (MMAC) Sixth Annual Energy Symposium, April 11, 2003.

[34]To the extent that new generation is needed to meet the higher 10 percent RPS targets in 2008 or earlier, the model implicitly includes a portion of the planned announcements by utilities.

[35] Wisconsin Department of Natural Resources, *Wisconsin Greenhouse Gas Emission Reduction Cost Study, Report 3: Emission Reduction Cost Analysis*, July 1997.

[36] EPA, energy CO2 inventories by state, http://yosemite.epa.gov/oar/globalwarming.nsf/content/EmissionsStateEnergyCO2Inventories.html